Testimony of
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Before the Committee on Energy and Natural Resources
United States Senate
July 24, 2002

Thank you for the invitation to speak to you today about the nation's energy infrastructure. My colleagues on the Federal Energy Regulatory Commission and I share this Committee's concern over the adequacy of America's energy infrastructure. It has been proven repeatedly that without enough power plants, transmission lines, fuel supplies and customer demand response, electricity becomes less reliable and wholesale prices become more costly and more volatile. Dependable, affordable, competitive wholesale energy markets rest on a three-part foundation: adequate infrastructure, sound market rules, and vigilant oversight of the marketplace. Weakness in any one element can hurt markets, hurt American energy customers, and ultimately impact the entire U.S. economy. FERC is working hard to set clear rules that promote all three goals.

Today I will address several issues. First, I will review how electric infrastructure affects wholesale electric markets and offer some examples drawn from the Commission's regional infrastructure studies and conferences. Second, I will talk about the steady growth in the nation's natural gas pipelines as a significant success, reflecting both the solid competition in the natural gas commodity market and sensible economic regulation of the pipeline industry. This is the model we hope to emulate, in part, with our Standard Market Design initiative in electricity. Third, I will look at the importance of technology and innovation to improve the quality of today's infrastructure and leverage it into the future. Last, I will talk about FERC's strategic plan and the resources we have committed to promoting infrastructure adequacy.

Infrastructure and Wholesale Electric Markets

It has long been understood that without adequate electric infrastructure, grid reliability becomes compromised and costs rise. In decades past, this was less of a problem than it is today, because state regulators ordered utilities to build more power plants and transmission lines to connect the plants to the customers and acted to assure cost recovery for those investments. Reserve margins generally exceeded twenty percent, reliability was good, and utilities rarely balked at making new infrastructure investments.

President Bush's National Energy Plan offered numerous recommendations addressing the nation's energy infrastructure. Consistent with the Plan, the Department of Energy recently issued the National Transmission Grid Study, which does an excellent job of explaining the vital role of the transmission grid and the consequences of our national failure to invest in it. Today's 150,000 mile high-voltage transmission system was originally built by integrated utilities to deliver electricity from large, remote power plants to their customers; the grid was then expanded and interconnected among utilities and regions to improve reliability by sharing excess generation.

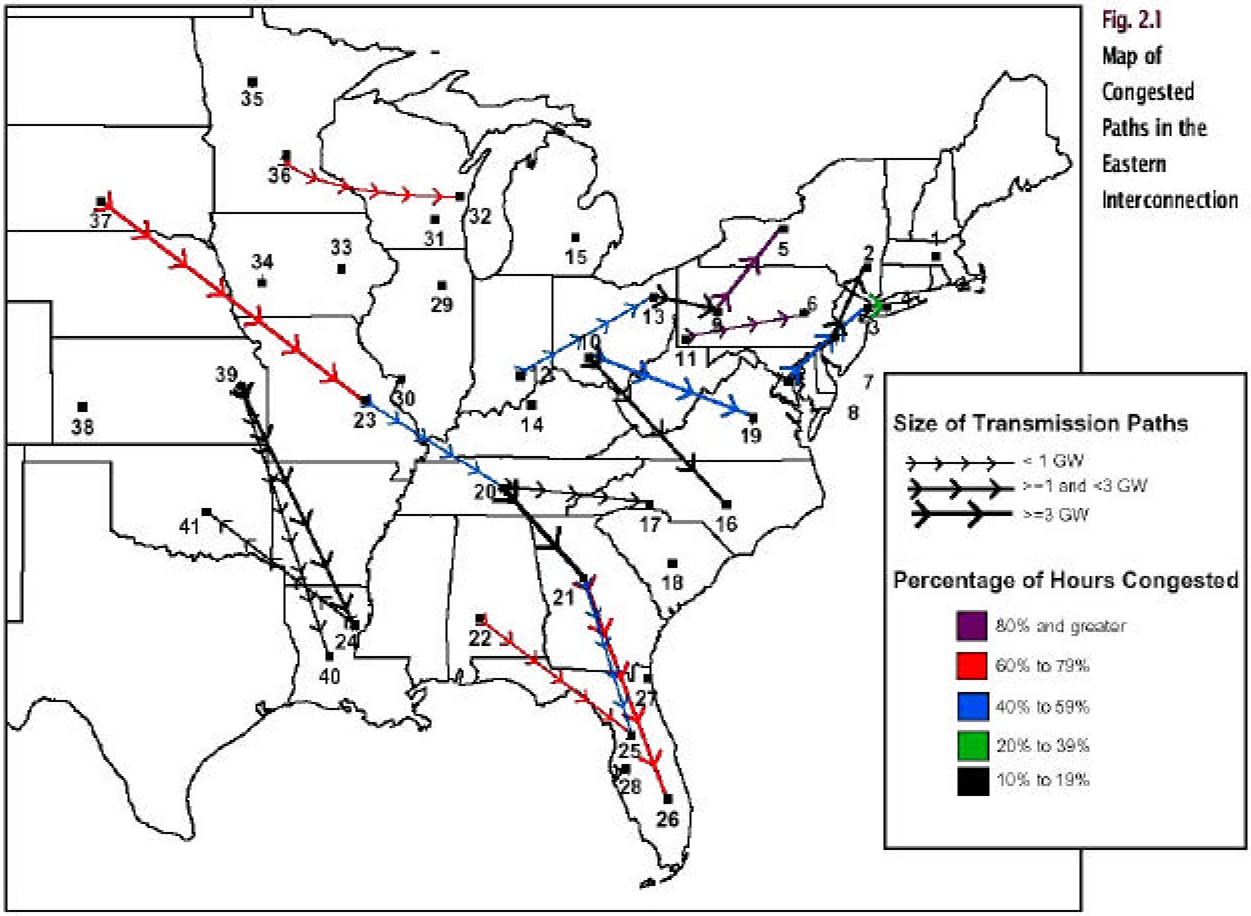
But the situation is very different today. For the past decade, most of the new generation in the country has been built by independent merchant generators rather than by vertically integrated utilities. As it became harder to site new transmission lines and returns on investment appeared to be more dependable in other sectors, investment in new transmission fell behind the pace of economic growth and electric load growth. Although the economy grew by 40% between 1989 and 2000, during that same period electric demand grew by 29% while transmission mileage increased by only 11%.

As Americans' energy demands have grown, the high-voltage grid has become increasingly congested, increasing costs across the board for most customers. Across the country, transmission constraints limit the amount of electricity that can flow from one region into another. Most constraints raise prices – for instance, constraints cost California electricity customers $222 million for congestion alone between September 1999 and December 2000. In other cases – inside southwest Connecticut, in New York City and Long Island, on the Wisconsin-Upper Michigan Peninsula, and elsewhere -- transmission constraints limit electricity imports to such a degree that it can become a daily challenge for the local utility to keep the lights on when temperatures peak and raise demand, or when local generators fail inside the electrically isolated "load pocket".

Figure 1 (on the next page, from DOE's study) shows some of the major transmission constraints in the Eastern Interconnect, the degree to which each is congested, and the direction of the flow. Many of these constraints occur within broad regional markets, limiting the ability to deliver power from one sub-region into another – for instance, there are large concentrations of generation in Maine seeking to export into the Boston and central New England market. Similarly, many generators concentrated in the lower South and Midwest are trying to sell into Florida.

DOE and FERC have concluded that the lack of a strong, nation-wide transmission system is limiting effective competition, raising costs to all electric customers, and risking reliability in many areas. We must begin working to relieve these transmission bottlenecks, pursuing broad regional interests and needs. DOE's National Transmission Grid Study recommends the creation of multi-state planning entities with a long-term time frame and inclusive process to identify needed transmission, generation, and efficiency improvements that will benefit entire regions. FERC will be considering such a process in our Standard Market Design proposal, due out at the end of July. The National Governors Association recently issued a thoughtful report calling for regional planning for energy infrastructure. I strongly endorse its recommendations. Cooperation and mutual support between states and governments at every level will be essential if we are to solve these pressing infrastructure challenges.

Figure 1: Map of Congested Paths in the Eastern Interconnection
Source: U.S. Department of Energy, National Transmission Grid Study



But neither FERC nor DOE can solve the siting problems that impede most new transmission construction. Most citizens oppose the siting of new transmission lines close to their communities, and their opposition can delay or kill a new line. Since citizen opposition will not change, we can only deal with this challenge by: motivating state regulators to use their siting authority in a more aggressive yet cooperative fashion; using energy efficiency, load management, distributed generation and demand response to limit the number of new lines needed; and using new transmission technologies such as FACTS (Flexible Alternating Current Transmission System) and advanced conductors that can transmit more energy through a given cable to maximize the grid assets already in place. FERC fully endorses the DOE Grid Study's thoughtful recommendations on transmission planning and siting.

A healthy grid needs not only new transmission, but also new generation sited in locations that are beneficial to the grid as a whole. To date, generators have built wherever they can build most cost-effectively, which tends to be at locations which combine access to available transmission, available gas pipelines, cooling water, and welcoming communities. Although traditionally the interconnection of new generation has been negotiated on a case-specific basis between each new generator and its host utility, FERC recently began working to develop a standardized interconnection contract and process to assure that every new generator is treated fairly, consistently and promptly. This rule, and the policies pertaining to how we pay for new interconnections and grid expansions, are now under consideration and out for public comment. These policies should be decided by the end of the year and should add further clarity and certainty to the investment climate.

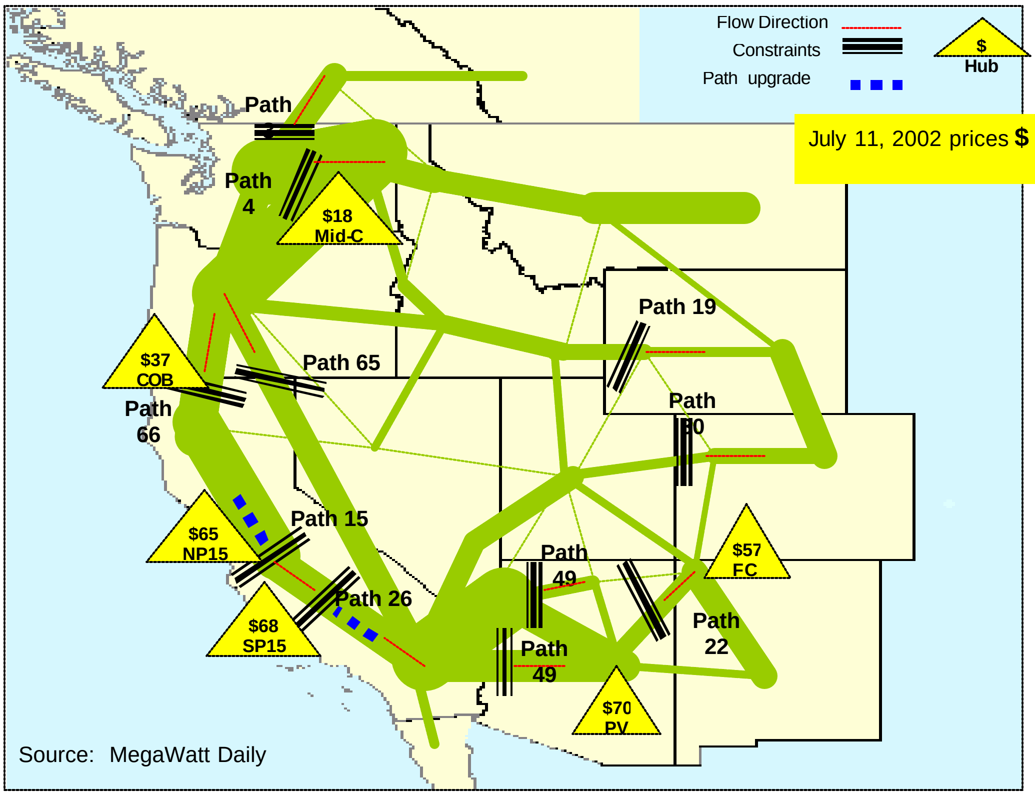
Regional Infrastructure Conferences

Over the past year, FERC has held three regional conferences to conduct in-depth studies of the broad conditions of the area's energy infrastructure, and to understand the issues in each region. These conferences have featured fact-filled presentations on the state of each region's energy infrastructure (electric power plants, fuel sources, hydro facilities, gas pipelines, electric transmission system, and other relevant information), demographic and energy load forecasts, and panels of experts talking about specific issues. Each conference has enjoyed strong attendance from state energy regulators as well as industry members and concerned citizens, enabling wide-ranging discussions about key regional concerns. The presentation materials for these conferences are available from FERC's website (see Attachment A). We will be holding the Midwest conference this fall in Chicago and going to the Southwest in early 2003.

The first conference, in Seattle on November 2, 2001, studied the Western states; the data developed then was updated last week to lay a foundation for our Western electric markets orders. The Western states are highly interdependent for their electricity and gas supplies, and have only a 10% reserve margin for electricity. While electric load has been growing at over 3% per year in the region, the Western states face slow growth in generation due to the "tabling" or cancellation of over 40,000 megawatts (MW) of planned power plants (California alone accounts for over half of this number). California and the Pacific Northwest are highly dependent upon hydro-electric generation, which is in turn dependent upon yearly rain and snow levels; the extended drought years from 1999 through 2001 dropped hydro-generation availability by 40%. California imports on average 20% of its electricity each year, and imports 85% of its gas to generate over 50% of its electricity in plants that are old, unreliable, expensive and inefficient. But while new interstate gas pipelines are being built across the West, little or no bulk transmission has been built to span the long distances between generators and customers, or to deliver more inexpensive electricity between sub-regions. The net result is that the inefficiencies and shortages in the California electricity market drive up prices across all other Western states, while the lack of new transmission and demand response means that congestion costs are increasing and reliability is decreasing in many areas. For this reason, the Commission deemed it necessary to continue a tighter market mitigation regime than exists in other established wholesale electric markets.

Figure 2 (below) shows how transmission constraints hamper the free flow of electricity and cause price differentials between constrained sub-regions of the Western Interconnection. Note how the bottleneck at the California-Oregon border effectively keeps most cheap hydro-power bottled up in the Northwest, where prices stay low (recently at \$18/MWh), and limits flow south into California; how the limited flow along Path 66 pushes electricity prices to \$65/MWh north of the Path 15 constraint and \$68/MWh south of that constraint (although in other seasons the price differential is reversed and higher to the north than the south); and how coal- and gas-fired generation in Arizona and New Mexico is bottled up east of the Path 49 constraint. These constraints impede competition between generators and fuels and raise prices for customers inside the constrained areas (also called load pockets).

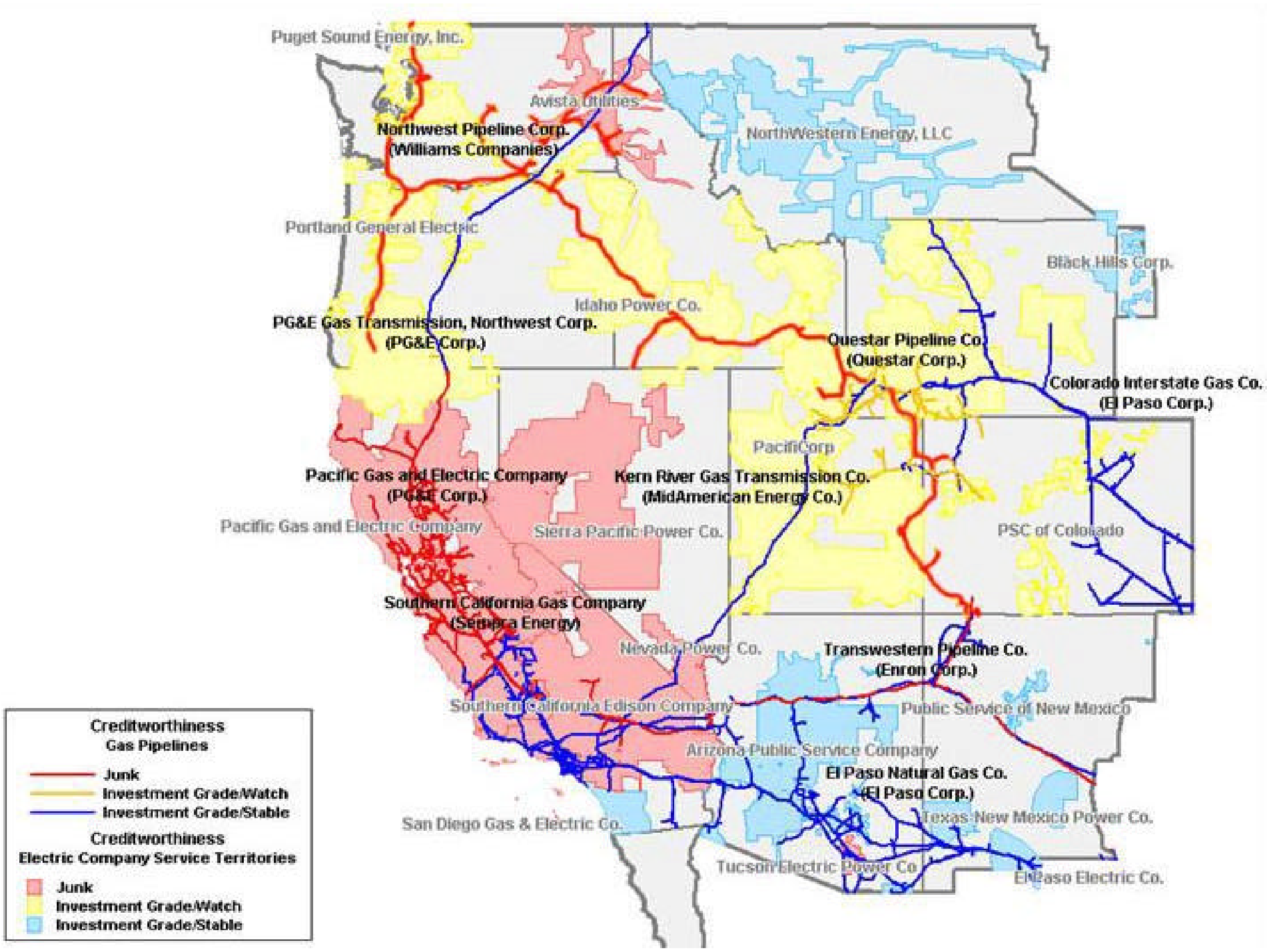
Figure 2: Western Transmission Constraints Cause Price Differentials



Looking ahead, we see several significant problems relating to Western infrastructure. This summer, there are very tight reserve margins in California and in the Arizona-Nevada-New Mexico areas. If either area experiences high generation outage rates (as is possible in California, with an aged fleet of fossil units) or loses much import capability (as happened recently on the Bonneville Power Administration system and in Arizona near Palo Verde due to fires near high-voltage transmission lines), they could face reliability problems. Over the long term, new infrastructure is not being funded because there is little confidence that new facilities will be profitable. Most infrastructure is built after funding is assured through the acquisition of long-term contracts with creditworthy partners; yet with so many of the utilities in the West either bankrupt or in junk bond status (see Figure 3, on next page), few infrastructure investors are willing to risk investments in the West. Additionally, it is hard to build in the West because so much of the land is owned by either federal agencies or Native American tribes; it can be a

Figure 3: Downgraded credit ratings may impact infrastructure expansion across the West

Source: RDI PowerMap, Standard and Poor's ratingsdirect.com



challenging and lengthy process to route a transmission line across these lands. With population growing significantly in the Southwest and Northwest, once-excess electricity and natural gas in those regions will become unavailable to export to California – which will exacerbate shortages in the near future. And last, with the entire region so dependent upon hydroelectricity, it remains highly vulnerable to droughts. The financial consequences of such shortages could again ripple across the entire West.

In the Northeast, there are two main infrastructure stories. The first is the difficulty of siting new transmission and gas pipelines in densely populated areas. Although the Northeast, like every other region, has a growing population with a large appetite for gas and electricity, few want to live near transmission lines, power plants or gas pipelines. Thus it is hard to site new power plants next to the load centers where customers live (as is needed inside New York City, Long Island, and southwest Connecticut), or to route new gas pipelines (as with Millennium into the New York City area) or transmission lines (into southwest Connecticut or across the Long Island Sound) into these dense urban areas. It is also difficult to motivate the people in one state to live next to, much less pay for, lines which will benefit their neighbors but not themselves. As long as these obstacles persist, the costs of doing nothing will mount -- FERC estimates that current levels of transmission constraints into southwest Connecticut, southeast Pennsylvania and eastern New York are costing electric customers as much as $1 billion extra per year in energy costs.

A second, more positive trend is the development of several proposed merchant (non-utility) electric transmission lines, for-profit businesses which propose to build new high-voltage transmission lines to connect loads with energy sources. These include the Neptune Regional Transmission project (which will bring 4,800 MW from Nova Scotia, New Brunswick and Maine to Boston and New York City), the TransEnergie Cross Sound project (which would move 330 MW between New Haven, CT and Long Island, NY), and the TransEnergie Lake Erie project (which would transmit 975 MW from Ontario across Lake Erie to either Ohio or western Pennsylvania). I strongly support the development of for-profit transmission. FERC is working to assure that independent transmission companies have a clear opportunity to earn appropriate rewards for the investment risks these projects pose.

While the Northeast is dominated by aggressive competition between wholesale generators, with retail competition in most states, the Southeast is characterized by large, vertically integrated utilities under traditional cost-of-service regulation, with extensive generation portfolios and limited opportunities for independent generators. Electric demand in the region is expected to grow by 20 to 30 percent over the next decade, primarily fueled by natural gas, even as gas production in the Gulf of Mexico declines. The grid in the Southeast was designed to move generation from plants to nearby loads, so it is inadequate to serve the needs of the competitive wholesale market, which seeks to move low cost generation in bulk from the Midwest and central south into Florida and the Mid-Atlantic states. And absent a liquid power market, incumbent transmission companies have tended to act in ways that favor their own generation and impede power flows for independent generators.

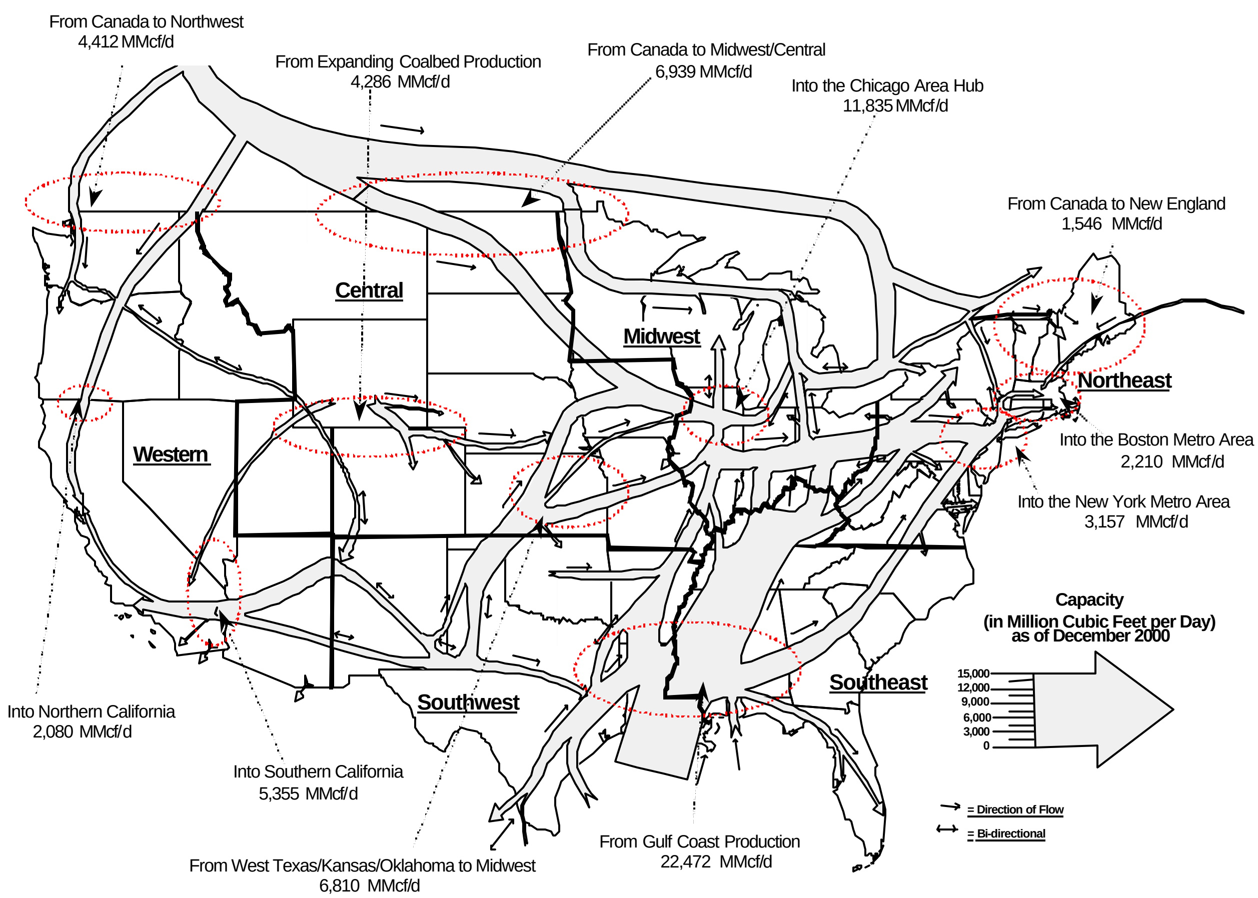
The central question to be resolved in the Southeast is, who should pay for the new transmission facilities that are desperately needed for the region as a whole? Much of the demand for generation (and thus the beneficiaries of new bulk transmission lines) comes from neighboring states, but the new power plants are being built in more central states. Although the residents of Mississippi, Alabama and Louisiana are benefiting from the investment dollars, jobs and tax benefits of these power plants, they are reluctant to pay for any new transmission lines that may be needed to enable these plants to reach their intended interstate markets. Similarly, utility customers in Florida and other power-hungry states don't want to pay to build new power lines outside their utilities' service territories, even though they want the energy those lines will deliver. Without regional planning and some wide-ranging balancing and reallocation of the costs and benefits of this needed infrastructure, overall delivered energy costs will continue to rise and competition between regions and efficient plants will be stifled. I am hopeful that state participation and cooperation can help solve this difficult problem.

Although it has become a cliché in the past six months, it is worth repeating that the energy sector has been hard-hit by the collapse of Enron, investigations by FERC and others into energy trading problems, and recent business accounting improprieties. Many of the energy companies that were planning to make significant infrastructure investments only a year ago have since cancelled their plans or sold off assets to improve their financial profile. Others would like to go ahead but cannot find creditworthy customers to back their plans with solid contracts. Thus, a strong economy and a strong dose of confidence and stability in the nation's energy markets will be needed before the perceived level of infrastructure risk improves and major new energy investments begin.

<u>Gas Pipelines as a Regulatory Success Story</u>

America's gas pipeline system has the capacity to carry over 105 billion cubic feet of natural gas per day from Canada, Mexico, the Gulf of Mexico, and domestic producers across the nation to local distributors and end users. (See Figure 4) It consists of over 180,000 miles of high strength steel pipe, with regularly spaced compressor stations to boost the pressure of the

Figure 4: Major Natural Gas Pipeline Transportation Routes and Capacity Levels, 2000
(Source: Energy Information Administration, December 2000)



gas inside the pipe and keep it moving. The pipeline system is supported by underground storage caverns, which hold about 20 percent of the gas consumed each winter to assure reliable delivery when needed.

The gas pipeline system has been steadily expanded over the years. Today there are over 60 major pipeline projects proposed by private investors, funded on the strength of long-term contracts and other commitments for gas. These projects will build another 5,600 miles of pipeline at a combined investment cost of over $9.8 billion, to transport another 20 billion cubic feet of gas per day (a 20% increase over current levels). Additional liquefied natural gas import facilities are also planned for near-term investment, to supplement the nation's aging gas production fields with new supply sources. Amid these expansion plans, however, several large projects (including the Independence line that was sponsored by Williams, El Paso, and National Fuel and Williams' Western Frontier project) have recently been cancelled due to softness in the short-term market and some financing problems.

There are several reasons why expansion of the gas pipeline system has been more successful than expansion of the electric high-voltage system. First, on the gas side there is a relatively small number of large interstate pipelines, so each player must take a broad, multi-state view and has both control of and accountability for the full geographic span. These companies can secure siting, eminent domain, cost recovery and rates approvals at FERC. In contrast, electric transmission companies tend to have a smaller footprint, so they have little motivation to participate in a multi-state, region-wide project that benefits customers outside their home turf. In addition, electric utilities face regulation both at FERC and by state regulators, who may be reluctant to approve rates for projects without significant local benefit.

Second, the criteria for pipeline approval and cost recovery at FERC have been clear and stable for a decade, so pipeline investors face a relatively clear and certain regulatory environment (other than the siting risks). On the electric side, the transition to competition varies by state and FERC's progress toward Regional Transmission Organizations, Standard Market Design and rate recovery are just now becoming clear. Last, when FERC issues a certificate to approve a gas pipeline that authority includes the right of eminent domain if necessary to acquire pieces of the pipeline route. FERC environmental and routing approval is lengthy, but swifter than the multi-state review required for major electric lines.

I believe that Standard Market Design and standard interconnection rules for new generation will do for electric infrastructure what gas rules have done over the past decade – stabilize the rules for all market participants, create certainty so that the road to market success becomes clear and predictable and risks are easier to identify and evaluate, and establish meaningful incentives for new construction with clear path to cost recovery.

Another infrastructure issue related to natural gas is the fact that although the nation's power plant portfolio is relatively diverse today, over 95% of the new power plants coming on-line in the nationwide are gas-fueled. Gas demand to serve power plants is so great – even with recent plant cancellations – that almost all of the demand for new pipeline capacity is to serve electric generators. Pipelines into the Northeast, Southwest and California are already fully subscribed, and new pipelines are becoming fully utilized as soon as they come on-line. This high level of pipeline utilization, and the competition between bulk customers and regions for available capacity, is raising significant gas allocation and service reliability issues up and down the pipelines. At the same time, production from a number of the nation's premier gas production areas is flattening, especially in the Gulf of Mexico, Permian Basin, and elsewhere, so it is likely that new gas sources and routes will be needed over the long run.

Technology Leverages Infrastructure

There are a number of ways that new technologies will allow us to leverage our existing electricity infrastructure system in innovative ways. Some of these include strategies to better use the existing grid, through energy efficiency, distributed generation, and demand response; transmission enhancements such as grid optimization through better data collection, enhanced power device monitoring, and advanced conductors; and using new technologies to use the grid in different ways, including advanced power electronics, high voltage direct current lines, and new cables such as high temperature superconducting cables.

Energy efficiency includes classic energy conservation and load management. Energy conservation devices such as compact fluorescent light bulbs and high-efficiency appliances and windows reduce total energy use across the board. Load management reduces peak loads, either by eliminating or reducing the activity (as by cycling residential air conditioners on and off during peak use hours) or by moving the activity to off-peak hours. Energy efficiency is an essential way to leverage existing transmission assets because it allows customers to get more results from each MWh consumed – for instance, the combination of passive solar architecture with insulated building shells and windows, a "cool roof" (low heat-absorbing), and efficient appliances and plug loads inside a home or office building significantly reduces the energy used to keep its occupants cool and effective during summer peak hours. Thus the building consumes much less electricity during peak hours and uses less of the limited assets of the local generation and transmission system. This reduces total energy use, lowers summer air pollution, and improves urban reliability within the load pocket – often at lower net cost than adding new generation or transmission.

Demand response is a crucial element for efficient grid use, as well as an effective deterrent to the exercise of supplier market power. Demand response moves a step beyond energy efficiency, to empower customers to change their energy consumption in response to energy prices over time. Most retail customers see flat, "after-the-fact" electric prices that give little hint of the underlying cost of energy production; they don't reflect scarcity, as when total demand outstrips supply and purchasers compete for the limited power available, or the higher production costs that occur when more inefficient (and costly) power plants are brought on-line. Most customers have a sense of when a product or service costs too much, and many would be willing to use less electricity when it costs more. Demand response programs give customers this opportunity, using technologies ranging from real-time pricing with "smart meters", to time of use rates with interval meters, or classic interruptible and curtailable programs which reward customers for sudden power reductions. Such programs allow grid managers to leverage existing grid assets by reducing peak loads and thus improve the ability of a constrained grid to serve more customers reliably. Demand response, energy efficiency and distributed generation programs can be targeted within constrained load pockets to relieve strains on the grid and delay asset exhaustion – this is being done in New York City, Southwest Connecticut, Chicago, and elsewhere.

Distributed generation (small generators using renewable or fossil fuels) can be used close to load centers to improve grid reliability while reducing the need for new transmission and reducing transmission line losses (the need for additional generation to replace energy lost due to resistance along the lines). Distributed generation includes solar photovoltaics (as on home rooftops), small wind generators (as at farms and oilfields), combined heat and power (once called cogeneration, used at office buildings and industrial sites), diesel- or natural gas-fired reciprocating engines (as for hospital and industrial emergency generators), and newer technologies such as fuel cells, microturbines, and flywheels (technically a form of energy storage). These are often installed by customers who wish to improve site reliability, reduce or stabilize energy costs, reduce environmental impact, or gain greater independence from the grid. Used in urban areas and at transmission substations, distributed generation can improve local voltage stability, reduce the need for imports into the urban area, expand the capability of local substations, and reduce net emissions from power generation.

It is also possible to enhance the operation of existing grid assets. One way to do this is to collect better data on the condition of the grid in real-time, using direct system voltage and flow sensors and dynamic power device monitors to better measure system operating conditions. This allows operators to manage the system less conservatively without sacrificing reliability, and run the system closer to its true capabilities. Improvements in system optimization modeling are giving grid managers a more sophisticated and wide-scale understanding of grid conditions and interactions, so they can use transmission and generation dispatch more effectively and reliably. And recent improvements in the materials used to make transmission conductors (high voltage cables) are improving the voltage carrying capacity of the wire, so it can be used under higher temperatures and often at lighter weights. These conductors can be used to replace existing wires in a strained transmission system, so the same right-of-way and towers can support greater throughput after reconductoring. Although these cables are not inexpensive, they are an attractive way to get more energy into constrained urban areas that face opposition to new transmission lines.

It is worth noting that once Regional Transmission Organizations are in place, they will have the analytical tools and regional scope to operate the transmission grid and generation resources more effectively than is currently possible for smaller utilities and ISOs. RTOs will also be charged with facilitating the integration of demand response into wholesale markets, as a way to balance against generator market power. RTOs will be the coordinators and facilitators for a very open regional power planning process, which should encompass not only which new transmission lines are needed, but also how to use energy efficiency, demand response, distributed generation and smarter generation siting to better manage existing and future grid assets for economy and reliability.

Last, there are a number of new technologies that offer opportunities to change the way engineers design and use the grid. These include high temperature superconducting cables, high-voltage direct current lines (HVDC, which can link asynchronous systems and perform long distance transmission with low losses), and flexible alternating current transmission system devices (FACTS, which is a set of power electronics technologies that allow rapid, precise control of grid flows and eliminate loop flows). Many of these technologies, and others, are not fully commercial yet, but they offer great promise. Unfortunately, it will take some time before this promise is realized, because the energy industry today faces so much business and regulatory risk that its members are hesitant to take on increased technology risks as well.

DOE's National Transmission Grid Study offers a good overview of these technology options and opportunities, as does extensive work by the Electric Power Research Institute and other sources. Both sources note that if we wish to reap the benefits of such technologies in the future, we must continue to support and fund research and development efforts in the present.

Infrastructure in FERC's Strategic Plan

In September, 2001, the Commission adopted a strategic plan to support the vision of reliable energy markets. But it is impossible to achieve that goal without a sound energy infrastructure. Thus, the first of the three substantive challenges in FERC's strategic plan (see Attachment B) is to "Promote a secure, high-quality, environmentally-responsible energy infrastructure through consistent policies."

Agency objectives and major activities under this goal include:

1.1 Remove roadblocks impeding market investment – processing gas pipeline certificate applications and hydroelectric dam license applications, handling gas and hydro compliance matters, preparing the electric standard interconnection rule, and preparing for and conducting the regional infrastructure conferences; work with Council on Environmental Quality and other agencies to strengthen inter-agency coordination and shorten processing timelines;

1.2 Provide clarity of cost recovery to infrastructure investors -- process rate filings from gas and oil pipelines, and consider innovative rate proposals from electric transmission entities;

1.3 Proactively address landowner, safety and environmental concerns -- dam safety program, including inspections of 2,058 dam safety inspections, LNG reliability inspections, respond to landowner inquiries, conduct environmental analyses for new gas and hydro projects, incorporate reasonable environmental and safety provisions into new licenses, collaborate with stakeholders and conduct gas outreach activities;

1.4 Stimulate use of new technology -- become familiar with new technologies and their uses, ensure that rules enable the use of new technologies;

1.5 Promote measures which improve the security and reliability of energy infrastructure -- improve security at dams and pipelines, process applications for security-related cost recovery, protect critical energy infrastructure information, develop standards for electric industry cyber-security, and coordinate with other agencies and stakeholders to better understand infrastructure security issues and work proactively to reduce energy infrastructure vulnerability.

For fiscal year 2002, FERC has committed over half of our approximately 1,150 full-time employees to these infrastructure activities.

In sum, I believe that an adequate energy infrastructure is critical for the economic success of our nation. Infrastructure investments bring disproportionately high returns for society – new pipelines and transmission lines lower delivered energy costs by reducing congestion and improving competition and commerce between regions. Better infrastructure lowers costs by lowering supplier market power. It improves energy reliability and security. And thanks to the promise of new technologies and smarter operations, we may be able to get better grid operations without a bigger, more intrusive footprint on our physical environment. I urge your continued attention to this important, yet under-appreciated, problem.

Attachment A – FERC Infrastructure Information Sources

Western Infrastructure Conference, November 2, 2001
http://www.ferc.gov/calendar/commissionmeetings/Discussion_papers/07-17-02/A-3west.pdf

Northeast Infrastructure Conference, January 31, 2002
http://www.ferc.gov/electric/infrastructure.htm#northeast"

Southeast Infrastructure Conference, May 9, 2002
http://www.ferc.gov/electric/infrastructure/SE-Infrastructure-Slides.pdf

Western Market and Infrastructure Assessment, July 17, 2002
http://www.ferc.gov/calendar/commissionmeetings/Discussion_papers/07-17-02/A-3west.pdf

FERC and DOE Joint Demand Response Conference, February 14, 2002
http://www.eren.doe.gov/electricity_restructuring/ferc.html

FERC Mission and Strategic Plan
http://www.ferc.gov/about/mission/Marketwork.pdf

DOE National Transmission Grid Study
http://www.energy.gov/NTGS/reports.html

Attachment B

Federal Energy Regulatory Commission
Strategic Plan 2001-2005
Making Markets Work

Vision
Dependable, affordable, competitive energy markets support a strong, stable national economy.
Mission
The Federal Energy Regulatory Commission regulates and oversees energy industries in the economic and environmental interest of the American public.

Challenges and Objectives:

Challenge 1: Promote a secure, high-quality, environmentally-responsible energy infrastructure through consistent policies.

Objective 1.1: Remove roadblocks impeding market investment
• Ensure that sufficient supplies of energy are available to provide room for competition to succeed
• Identify transmission and pipeline projects with high public interest benefits and facilitate their speedy completion
• Standardize interconnection of power generation plants of all sizes and technologies
• Strengthen inter-agency coordination on hydropower licenses to shorten processing timelines
• Expedite gas pipeline certificate processes, consistent with due process

Objective 1.2: Provide clarity of cost recovery to infrastructure investors
• Establish a process to timely include prudently-incurred expansion costs in transmission and pipeline rates
• Ensure rate design for regulated company services supports long-term competitive markets
• Welcome balanced innovative rate and return proposals that incent pro-competitive behavior and publicly beneficial projects

Objective 1.3: Proactively address landowner, safety and environmental concerns
• Encourage applicants to address stakeholder concerns before the licensing/certification process
• Utilize collaboration with affected parties to the greatest extent possible
• Ensure strictest adherence to prudent safety practices
• Incorporate reasonable environmental conditions into permits and licenses

Objective 1.4: Stimulate use of new technology
• Develop industry and agency familiarity with most current infrastructure-based technologies

• Equalize regulatory treatment (including cost recovery) for old and new technologies in transmission, transportation, production and generation

Objective 1.5: Promote measures which improve the security and reliability of the energy infrastructure
• Work with other agencies and parties to identify security issues and needs
• Support industry efforts to improve infrastructure security

Challenge 2: Foster nationwide competitive energy markets as a substitute for traditional regulation.

Objective 2.1: Advance competitive market institutions across the entire country
• Complete firm establishment of regional transmission organizations with clear responsibilities, independence and scope
• Develop appropriate coordination role with states to efficiently oversee regional power markets
• Look to balanced, industry-led organizations to develop reliability and business practice standards
• Firmly establish transmission planning function on a regional basis, to use a variety of technology solutions to meet reliability, security and market needs

Objective 2.2: Establish balanced, self-enforcing market rules
• Link deregulated rate authority to continued presence of balanced market conditions
• Rely on international best practices to develop comprehensive market protocols/rules
• Work to establish robust programs for customer demand-side participation in energy markets
• Encourage standardized business rules and practices to maximize market efficiency, ease market entry, and reduce transactions costs

Challenge 3: Protect customers and market participants through vigilant and fair oversight of the transitioning energy markets.

Objective 3.1: Improve our understanding of energy market operations
• Keep abreast of market and technological innovation, including use of financial instruments and Internet-based energy trading
• Develop staff's investigatory and market data analysis skills through training, new hiring and relationships with outside experts
• Strengthen role of RTO market monitoring units

Objective 3.2: Assure pro-competitive market structures
• Identify and remedy problems concerning market structure
• Assess market and infrastructure conditions through use of objective benchmarks
• Periodically review effectiveness of market rules and revise them consistent with sustained, long-term development of energy markets
• Ensure that mergers and consolidations are consistent with pro-competitive goals

Objective 3.3: Remedy individual market participant behavior as needed to ensure just and reasonable market outcomes
• Identify and mitigate market power, and use prohibitions and penalties as necessary
• Initiate and conduct timely and effective investigations as warranted by factual reviews
• Act swiftly on third-party complaints, using litigation before Administrative Law Judges as necessary to determine factual issues
• Develop expedited dispute solving mechanisms to minimize time and personnel use

Challenge 4: Efficiently administer the agency's resources to accomplish the agency's goals.

Objective 4.1: Attract, train and retain staff to fulfill the Strategic Plan

Objective 4.2: Manage information technology to better serve the public and streamline work processes

Objective 4.3: Communicate our activities more clearly with customers, elected officials and industry
• Publish information that enhances public understanding of energy markets
• Proactively reach out to groups affected by agency actions for advance input

Objective 4.4: Integrate agency business planning and budgeting processes

Objective 4.5: Build strong partnerships with all stakeholders, particularly with governors and states